TITLE: REDUCING WATER PRODUCTION IN MISSISSIPPIAN RESERVOIRS USING GELLED POLYMER SYSTEMS

FINAL REPORT

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Submitting Organization: University of Kansas Center for Research, Inc. 2385 Irving Hill Road Lawrence, KS 66044

Participating Subcontractors:

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DISCLAIMER:

ABSTRACT:

The objective of this project was to extend gelled polymer technology to reduce water production and increase oil production in Mississippian reservoirs in Central Kansas. Conventional gelled polymer treatments were applied followed by a post placement process in which some of the gel that formed in situ was dehydrated by injection of oil to create flow channels that exhibit preferential permeability to oil and significantly lower permeability to water. The project consisted of two gel polymer treatments in the Mississippian formation in the Schaben Field in Central Kansas. Two wells(Humburg #1 and Borger #1) were successfully treated with ~4000 bbl of gelant and were dehydrated by injection of oil following insitu gelation. Water production was reduced in both wells by 250 to 300 B/D from the pretreatment rate. Savings in electrical costs due to reduced water production on the Humburg lease were estimated to be $500-$600/month following the gel treatment. Neither well produced much incremental oil and post treatment rates declined below pretreatment oil rates. Disproportionate reduction in water production was obtained in both tests. However, there was not enough incremental oil production to make either treatment economic. The high oil price adds an economic penalty to small reductions in oil rate following the treatment.

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INTRODUCTION

Objectives -

The objective of this project was to extend gelled polymer technology to reduce water production and increase oil production in Mississippian reservoirs in Central Kansas. Conventional gelled polymer treatments were applied followed by a post placement process in which some of the gel that formed in situ is dehydrated by injection of oil to create flow channels that exhibit preferential permeability to oil and significantly lower permeability to water. If this process was successful in the field, water production rates will be reduced substantially coupled with increased oil recovery. The project consists of two gel polymer treatments in the Mississippian formation in the Schaben Field in Central Kansas. These treatments were the first well-documented treatments using the chromium carboxylate-polymer system currently used to treat Arbuckle wells in Central Kansas.

Project Task Overview -

Task 1 Selection of wells for treatment

Tasks 2-6 will be done for Wells 1-3 as each well is treated.

Task 2 Prepare well for treatment

Task 3 Perform gel treatment

Task 4 Post treatment dehydration of gel

Task 5 Place well on production

Task 6 Analysis of Performance

Task 6.1 Analysis of data
Task 6.2 Preparation of reports and presentations

Task 7 Participate in SWC and PTTC Workshops

EXECUTIVE SUMMARY:

The project consisted of two gel polymer treatments in the Mississippian formation in the Schaben Field in Central Kansas. Two wells(Humburg #1 and Borger #1) were successfully treated with ~4000 bbl of gelant and were dehydrated by injection of oil following insitu gelation. Water production was reduced in both wells by 250 to 300 B/D from the pretreatment rate. Savings in electrical costs due to reduced water production on the Humburg lease were estimated to be $500-$600/month following the gel treatment. Neither well produced much incremental oil and post treatment rates declined below pretreatment oil rates. Disproportionate reduction in water production was obtained in both tests. However, there was not enough incremental oil production to make either treatment economic. The high oil price adds an economic penalty to small reductions in oil rate following the treatment.

RESULTS AND DISCUSSION:

***Task 1 Selection of wells for treatment*:** Two wells were selected for evaluation in this project. These wells were Humburg #1 and Borger #1. Buildup tests were conducted on each well using a computerized Echometer to estimate the kh of the well and the flow environment in the vicinity of the well. Figure 1 shows the location of the two wells. Table 1 summarizes data for these wells.

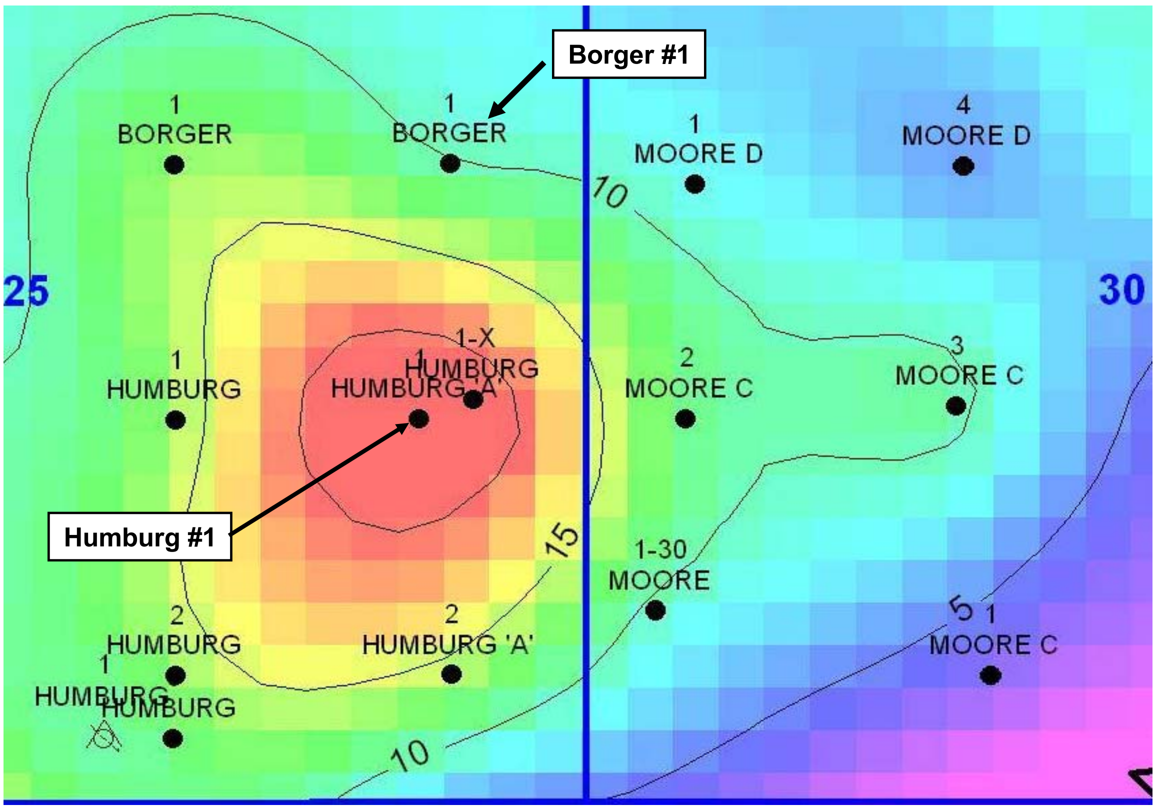

Figure 1: Map of Schaben Field Showing Candidate Wells (1)

Humburg #1 was selected for the first gel treatment in March 2007 because we estimated it would be possible to inject the gelant at rates commonly used for treatments. The estimated skin in Borger #1 for the production of oil and water is large and initially it appeared that it would not be possible to inject a viscous gelant solution (30 cp) into this well at rates used for treatments.

After examining buildups for other wells operated by American Warrior, the data from Borger #1 was revisited. A well log was located which indicated that the thickness of the productive interval was essentially the same as Humburg #1. Reevaluation of the data led to the decision to carryout a gel treatment in Borger #1 in the fourth quarter of 2007.

Table 1: Summary of Well Data-Pre Treatment Analysis

	Humburg #1	Borger #1
Operator	Pickrell Drilling Co	American Warrior Inc.
Depth to Top of Mississippian, feet	4390	4382
Completion	Perforated-4 shots/ft	Open hole
Interval open for production	4392-4400	4390-4396
Net Thickness open, ft	8	6
Oil Rate, B/D	2.7	5
Water Rate, B/D	391	445
Pump intake depth, ft	4054	4360
Type of pump	Rod	Rod
Fluid level above pump, ft	2600	1000

Pressure data from the buildup conducted in Humburg #1 and Borger #1 are presented in Figures 2 and 3.

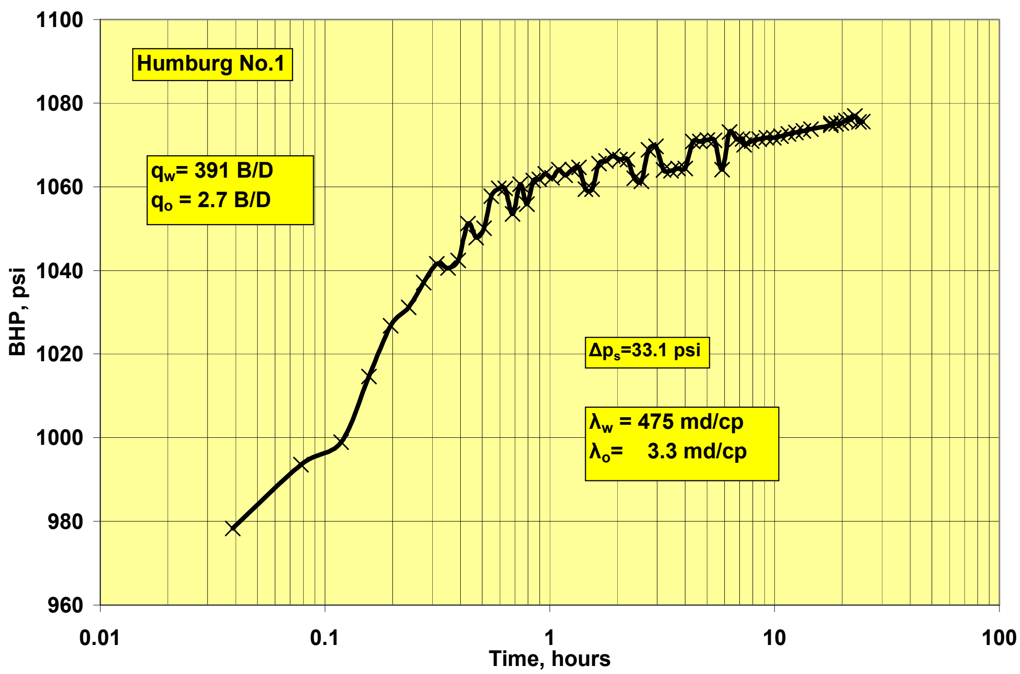

Figure 2: Pressure buildup in Humburg #1

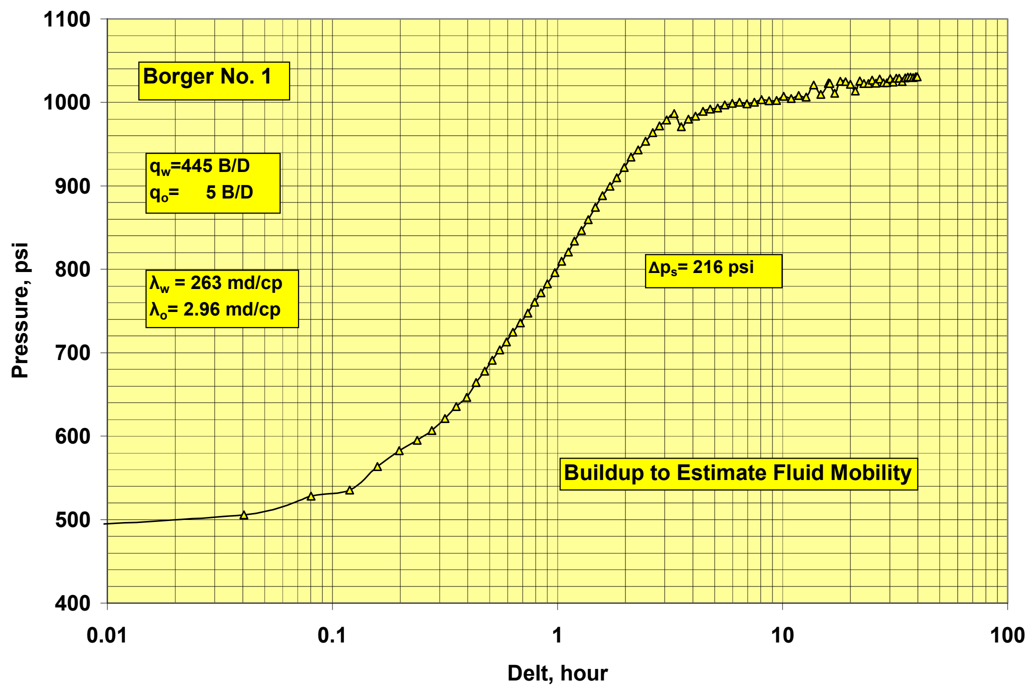

Figure 3: Pressure buildup in Borger #1

Humburg #1

Task 2 Prepare well for treatment

The well was prepared for the gel treatment by running 2 7/8" tubing on a packer set at 4374 feet. An acid treatment was done on March 14 to cleanout the well and the near wellbore area. About 2500 gallons of acid were used with 30 ball sealers dropped at a rate of 1/bbl after about 30 bbls of acid were injected. Final treatment rate was 5 BPM at a well head pressure of 1175 psi. An overflush of 100 bbls was used to displace the acid into the formation. Pressure indicated the balls hit the formation after the overflush began. Initial shut in pressure was 100 psi. The well went on vacuum 15 seconds after shut-in... About 187 bbls were swabbed back. Treatment appeared to be excellent.

Task 3 Perform gel treatment

The gel treatment began on March 16, 2007 and was completed on March 21, 2007. Treatment data are summarized in Table 2. The treatment used WC204 polymer with a chromium acetate crosslinker. About 4232 bbls of gelant were injected at rates varying from 0.51 to 0.77 BPM. Concentration of polymer was increased in steps in response to the pressure measurements. Maximum bottomhole pressure was 2891 psi during the last stage of gelant injection. The tubing was flushed with 20 bbls of water followed by 37 bbls of oil to displace the gelant from the tubing and casing into the formation prior to shutting in the well.

Figure 4 shows the BHP and polymer concentration as a function of cumulative volume of gelant injected during the treatment. Figure 5 shows the bottomhole temperature and polymer concentration during the treatment. Temperature of the gelant was 30 to 40 degrees F lower than the formation temperature when it was injected into the formation. The well was shut in to promote in-situ gelation for at least 14 days before the dehydration was scheduled to begin.

Table 2: Summary of Gel Treatment for Humburg No. 1

Stage	Date Begin	Time Begin	Date End	Time End	WC204® Polymer (ppm)	Gel Bbls.	Begin Surf. Pres. (psi)	End Surf. Pres. (psi)	Begin BH Pres. (psi)	End BH Pres. (psi)	Pump Rate Begin (BPM)	Pump Rate End (BPM)	Comments
1	3/16/07	10:54 a	3/17/07	5:54 p	2000	935	Vac	Vac	1196	1732	0.50	0.51	Stage complete
2	3/17/07	5:54 p	3/19/07	12:02 p	3000	1313	Vac	120	1732	2094	0.51	0.51	Stage complete
3	3/19/07	12:02 p	3/20/07	5:10 p	4500	1015	120	710	2094	2603	0.51	0.77	Stage complete
4	3/20/07	5:10 p	3/21/07	2:15 a	6000	420	710	900	2603	2789	0.77	0.77	Stage complete
5	3/21/07	2:15 a	3/21/07	6:00 a	8000	234	900	1000	2789	2885	0.77	0.75	Stage complete
6	3/21/07	6:00 a	3/21/07	2:23 p	10000	315	1000	1040	2885	2891	0.75	0.75	Stage complete
7	3/21/07	2.23 p	3/21/07	3:00 p	Water	[20]	1040	0	2891	1909	0.75	0.00	Stage complete
8	3/21/07	3:00 p	3/21/07	4:01 p	Oil flush	[37]	0	1150	1909	2595	0.00	0.60	Stage Complete
Totals						4232							

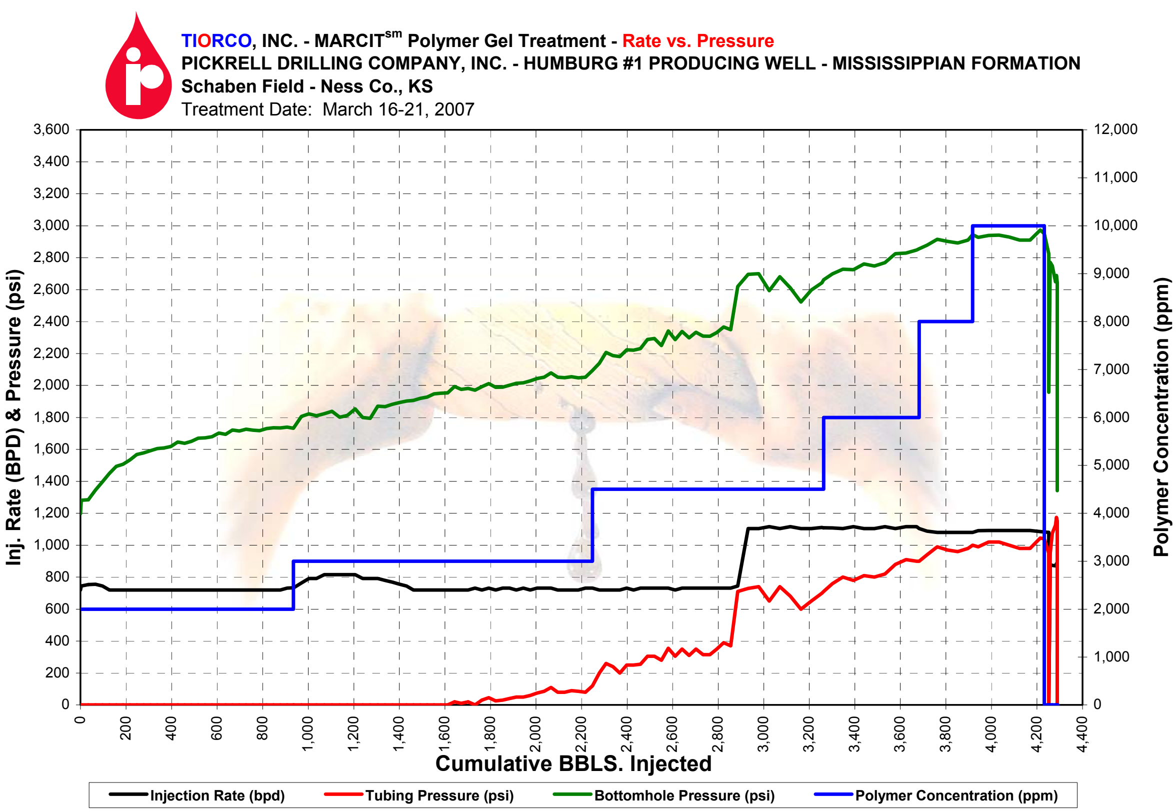

Figure 4: Injection rate, bottomhole pressure, surface pressure and polymer concentration versus cumulative volume of gelant injected.

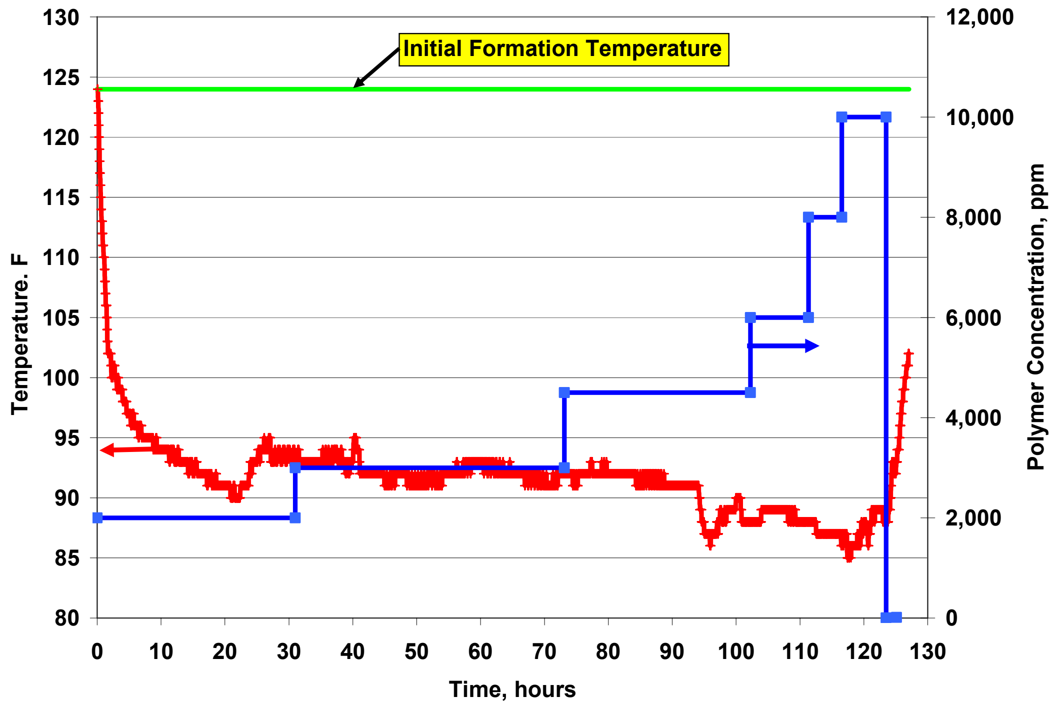

Figure 5: Bottomhole temperature and polymer concentration during treatment.

Task 4 Post treatment dehydration of gel

The well was treated with polymer gelant from March 16-21, 2007 and then shut-in from March 22-April 9(18 days). Muddy field conditions extended the shut-in time beyond the initial 14 days. Dehydration of the gel began on April 10 and was completed on April 21. About 119 bbls of oil were injected at an average rate of about 10.8 B/D. The slow injection rate was chosen to promote dehydration of the gel as opposed to destruction caused by excessive pressure gradients. Prior to gel injection, a pressure gauge was set at 4260 ft to record pressure continuously during the dehydration process. Initial bottomhole pressure at the beginning of oil injection was 1207 psi.

Figure 6 shows the bottomhole pressure and injection rate as a function of volume of oil injected during the dehydration treatment. Maximum pressure increase during the injection of oil was about 43 psi. The pressure declined rapidly to initial reservoir pressure at the end of oil injection. The small pressure increase during the dehydration process is consistent with similar data obtained in our DPR treatments in Arbuckle formations of Central Kansas. This indicates that the gel that was formed insitu following the gel treatment was easily dehydrated or displaced by the injected oil

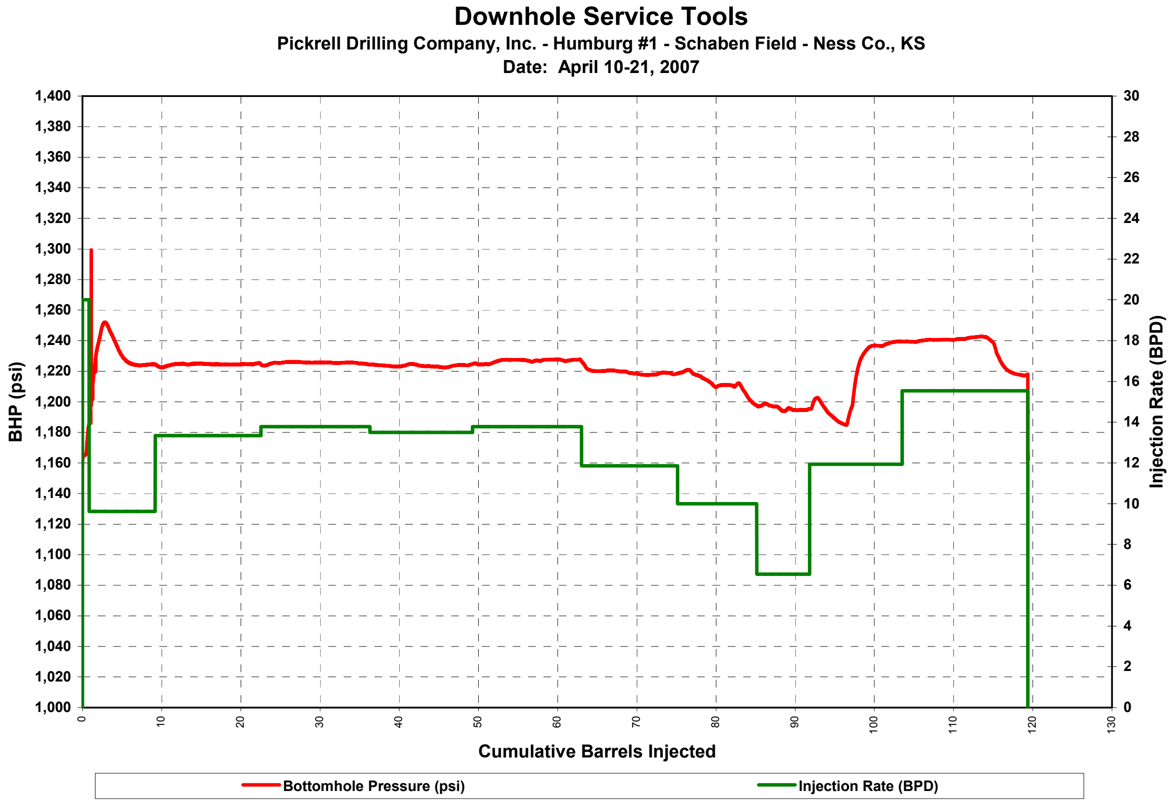

Figure 6: Bottomhole pressure and injection rate versus cumulative volume of oil injected during the dehydration of the gel after placement.

Task 5 Place well on production

The well was placed on production on April 26. Figure 7 shows the oil rate as a function of number of days on production after the treatment. The pretreatment oil rate was 2.7 B/D. Miscellaneous operating problems caused inaccuracy in determining the volume of oil produced in the first 12 days after the well was put on pump. Near the end of September, water production was about 156 B/D and the well was pumped off. The oil rate declined to about the pretreatment rate, so additional incremental oil was not anticipated.

Samples of produced fluid were obtained during the first 30 days after the well was placed on production and were analyzed for chromium (CrIII) and Total Organic Carbon. Polymer concentration as ppm TOC is shown on Figure 8. Maximum concentration was 204 ppm and concentration declined with volume of water produced. Results of the chromium (III) analyses are presented in Table 3. The average concentration of chromium was 0.36 ppm.

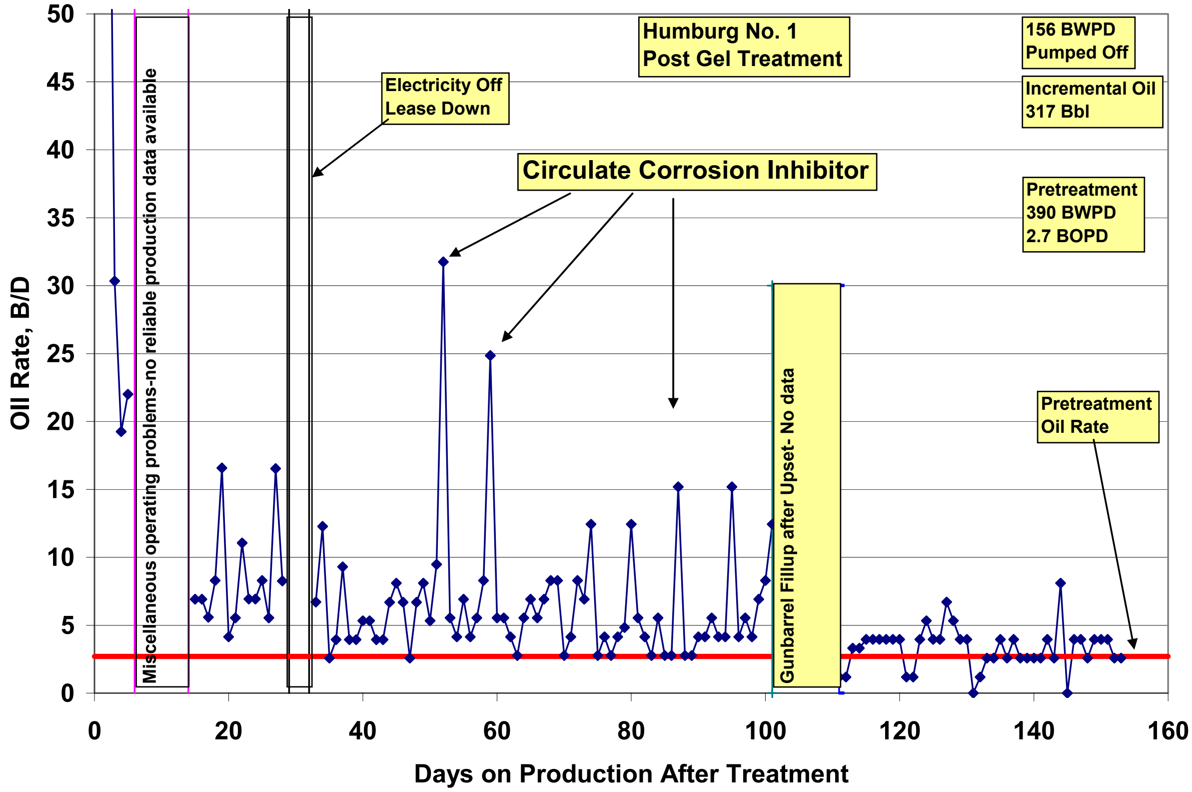

Figure 7: Oil rate following get treatment and dehydration of Humburg No. 1

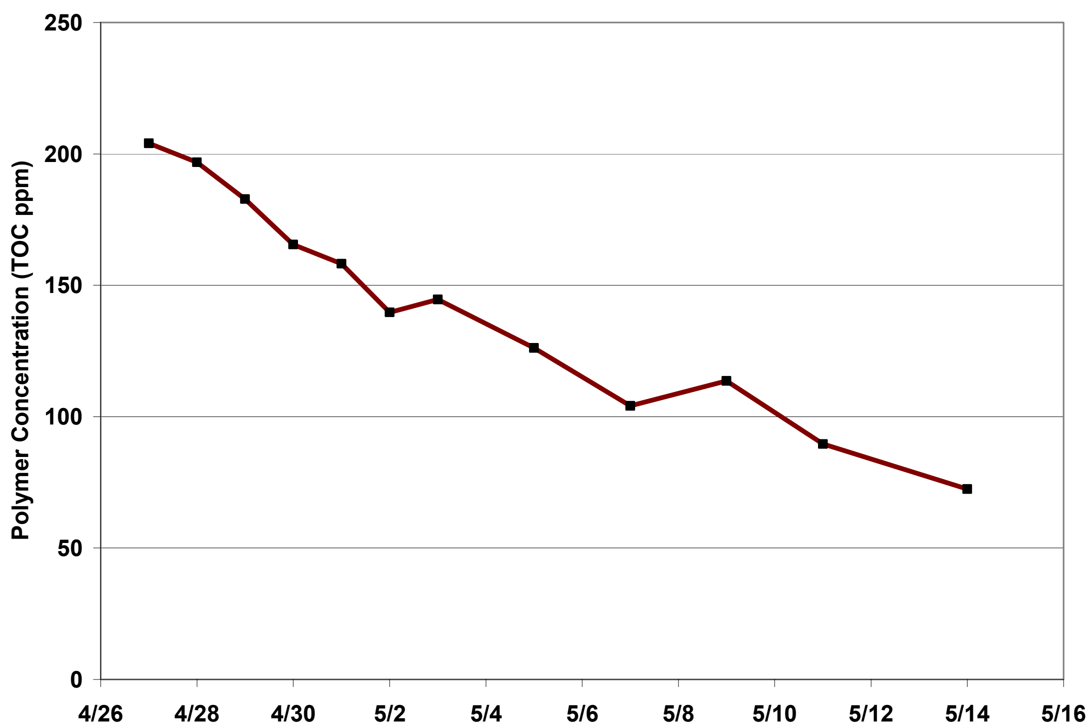

Figure 8: Polymer concentration in produced water after gel treatment-Humburg #1.

Table 3: Chromium (III) in produced fluid from Humburg #1 following gel treatment

Date	Chromium (ppm)
4-27-07	0.25
4-28-07	0.31
4-29-07	0.34
4-30-07	0.36
5-01-07	0.36
5-02-07	0.45
5-03-07	0.33
5-05-07	0.45
5-07-07	0.39
5-09-07	0.40
5-11-07	0.39
5-14-07	0.31
Average	0.36

Task 6 Analysis of Performance

Task 6.1 Analysis of data

Table 4 contains an approximate analysis of the incremental oil production from the gel treatment. Included in Table 4 is the oil that was not produced during the acidizing, gel treatment, the shut-in period and the gel dehydration period. This time interval is 42 days. The volume of oil that would have been produced at the pre-treatment oil production rate (2.7 B/D) is 113 bbls. The amount of incremental oil produced is about 317 bbls. Although incremental oil was produced, the increase in production rate was substantially less than observed following gel treatments of Arbuckle wells. The water production rate prior to treatment was ~393 B/D and the well was not pumped off. The gel treatment reduced the water production rate by about 237 B/D.

Table 4: Analysis of oil production response-Humburg #1-September 28, 2007

	Bbls
Total oil production from April 26	952
Oil injected during dehydration	[119]
Deferred production from March 16 to April 25	[113]
Pretreatment production from April 26 to September 28(2.7 B/D)	[402]
Incremental oil due to gel treatment	317

Incremental oil production ceased by September 30, 2007. However, water production remained at about 156 B/D with the well pumped off. By May 2008, water production was 142 B/D and oil production was 2.16 B/D.

The well is part of a three well lease with production wells run by electric motors. Electrical cost data for operation of the lease were gathered for the period before the gel treatment and for a limited period after Humburg #1 was treated. Monthly electrical costs for the Humburg Lease(3 wells) are presented in Figure 9. The lease electrical costs averaged about $500-$600 /month less than costs prior to the treatment for the period January 2005-December 2007. Electrical cost savings appear to be the result of lower lifting costs due to the reduction of the water production rate in Humburg #1. Although water production was reduced substantially which should be reflected in reduced electrical costs, the amount of incremental oil production was not sufficient to support the economics of gel treatment of this well to reduce water production.

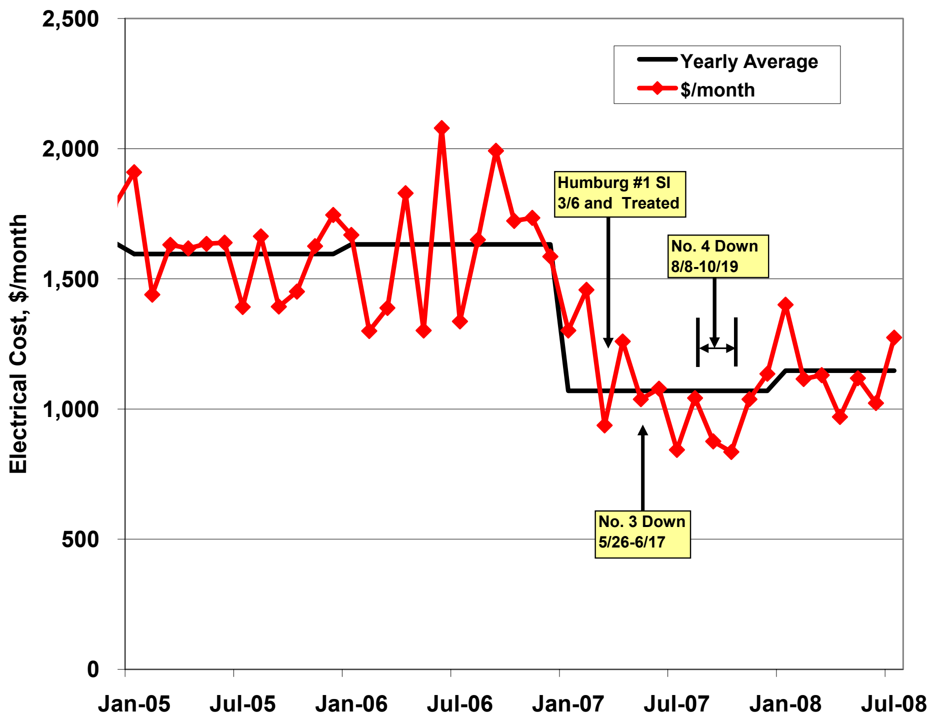

Figure 9: Electrical costs on Humburg lease before and after treatment of Humburg #1

Borger #1

Task 2 Prepare well for treatment

The well was prepared for the gel treatment by pulling the 2 7/8" production tubing and running a 2 7/8" production string on a packer. The packer was set at 4350 feet. The well was acidized with 2500 gallons of acid and swabbed to recover the spent acid.

Task 3 Perform gel treatment

The gel treatment began on September 24, 2007 and was completed on September 28, 2007. Treatment data are summarized in Table 5. The treatment used WC204 polymer with a chromium acetate crosslinker. About 4039 bbls of gelant were injected at rates averaging 1100 B/D. Concentration of polymer was increased in steps in response to the pressure measurements. Maximum bottomhole pressure was 2055 psi during the last stage of gelant injection. The tubing was flushed with 49 bbls of water followed by 35 bbls of oil to displace the gelant from the tubing and casing into the formation prior to shutting in the well. Figure 10 shows the BHP and polymer concentration as a function of cumulative volume of gelant injected during the treatment. The bottomhole temperature gauge malfunctioned and no data were obtained. The well was shut in to promote in-situ gelation for at least 14 days before the dehydration was scheduled to begin.

Table 5: Summary of Gel Treatment-Borger #1

	Date	Time	Date	Time	Polymer	Gel	WHP (psi)		BHP (psi)		Pump Rate (bpd		Comments
Stage	Begin	Begin	End	End	ppm	bbls	Begin	End	Begin	End	Begin	End	
1	9/24/07	2:20 PM	9/25/07	12:51 PM	2000	1014	vac	170	558	1524	1100	1100	stage complete
2	9/25/07	12:51 PM	9/26/07	4:21 PM	3000	1260	170	530	1524	1905	1100	1100	stage complete
3	9/26/07	4:21 PM	9/27/07	8:17 AM	4500	735	530	625	1905	1992	1100	1100	stage complete
4	9/27/07	8:17 AM	9/27/07	7:10 PM	6000	498	625	700	1992	2055	1100	1100	stage complete
5	9/27/07	7:10 PM	9/28/07	1:36 AM	8000	285	700	700	2055	1999	1100	1100	stage complete
6	9/28/07	1:36 AM	9/28/07	6:24 AM	10000	247	700	700	1999	1989	1100	1100	stage complete
7	9/28/07	6:24 AM	9/28/07	7:10 AM	0	30	700	900	1989	2189	1100	1100	Oil Flush
Totals						**4069**							

Task 4 Post treatment dehydration of gel

Dehydration of the gel following placement was carried out from October 11-22 by injecting oil at a rate of ~ 10B/D. Bottomhole pressures measured during the dehydration are plotted in Figure 11. With the exception of a pump problem in the first 10 hours, the bottomhole pressure averaged about 1480 psi with variations of about 20 psi during the entire treatment. Volume of oil injected was about 102 bbls. Oil displacement occurred at a steady state rate for the majority of the dehydration process. Average pressure increase was ~250 psi which is substantially higher than observed during the gel dehydration of Humburg #1 and Arbuckle wells .

Task 5 Place well on production

Borger #1 was placed on production following the dehydration treatment. Tubing and packer were pulled and a pump was run on the production tubing. Production data are not available for this well on a regular basis.

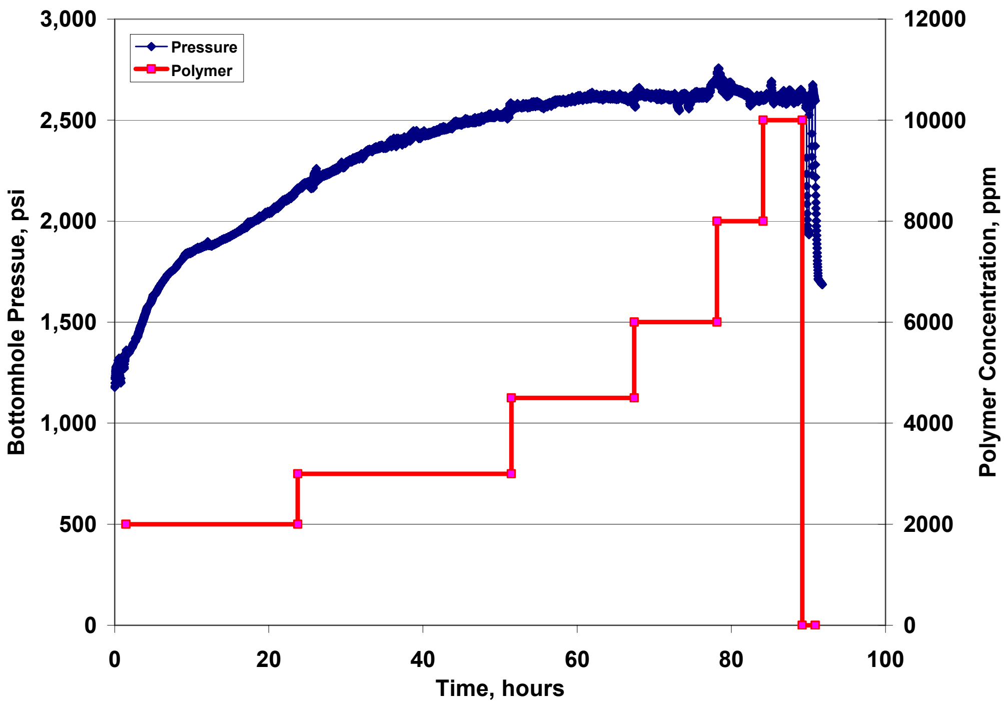

Figure 10: Bottomhole pressure and polymer concentration during the gel treatment of Borger#1

Task 6 Analysis of Performance
Task 6.1 Analysis of data

The well pumped down quickly to a rate of 145 B/D with oil cut of 2%. The corresponding oil rate was 2.9 B/D leaving a water rate of about 142 B/D. By December 2007, fluid production was 150 B/D with 2% oil cut. The oil rate of 3 B/D with the well pumped off was less than the pretreatment rate of 5 B/D. Water production was reduced from 445 B/D to 145 B/D, a reduction of 300 B/D. A well test in March 2008 was 107 bbls of total fluid with 3.5% oil. Water rate was 103 B/D and the oil rate was 3.75 B/D with the well pumped off Water rate was reduced by about 342 B/D from the pretreatment rate and the oil rate was gradually increasing. The oil rate was 1.25 B/D less than the pretreatment rate, which is a substantial economic penalty when the price of oil is over $100/bbl. Although the water rate was reduced substantially which should correspond to reduced electric costs, the loss in oil revenue from the decrease in oil rate after treatment makes this process uneconomic.

Borger #1 stopped pumping sometime in April. The well was pulled on May 5, 2008 and a hole was found in the last joint of tubing. Baker Petrolite inspected the equipment and reported that corrosion from sulfate reducing bacteria and the polymer treatment were contributing factors. The well remained down through July due to shortage of workover rigs for old wells.

Incremental oil production was limited and was not sufficient to justify the cost of the treatment as is expected in treatments of Arbuckle wells. A reduction of water rate of

~300-350 B/D was sustained after the treatment which will reduce electrical costs. Data on electrical costs were not available at the time this report was prepared.

Samples of produced water were collected during the first month the well was on production to determine chromium (III) and polymer concentrations. No chromium was detected in the produced water samples. Polymer concentrations, expressed in terms of Total Organic Carbon (TOC), are plotted in Figure 12. Polymer concentrations declined with time on production to low levels within a month. The concentration spike from the last sample collected is not consistent with the trend and may represent an anomalous sample. The amount of polymer in the produced water was negligible.

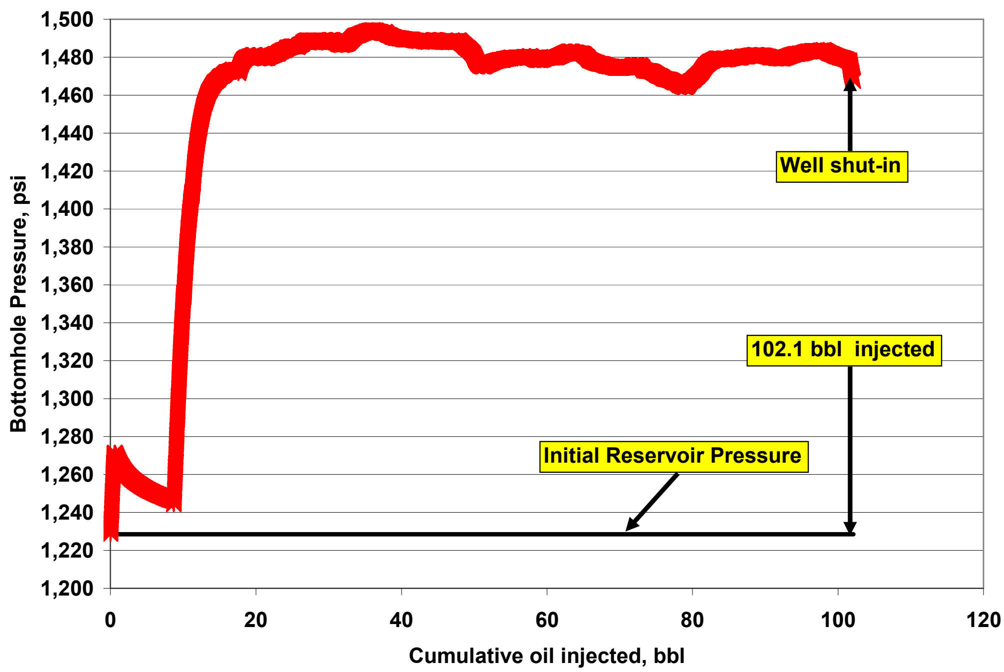

Figure 11: Bottomhole pressure versus cumulative volume of oil injected during gel dehydration in Borger #1

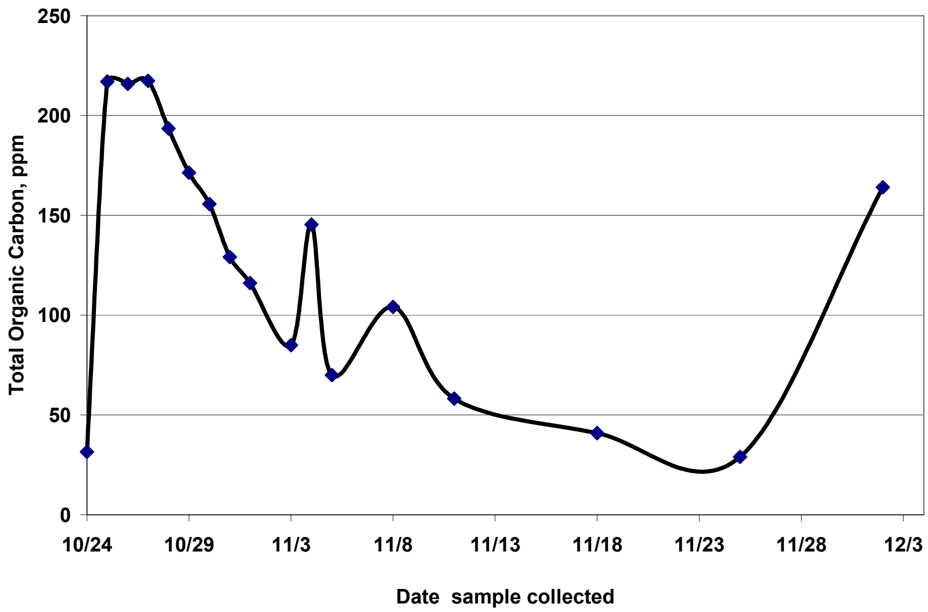

Figure 12: Total organic carbon in produced water from Borger #1

Task 7: Participate in SWC and PTTC Workshops

A poster presentation was made at the Oklahoma Oil and Gas Trade Exposition, October 26, 2006. A presentation was made at the Stripper Well Consortium Technology Transfer Conference in Pittsburg, PA on November 8, 2006. A PowerPoint presentation was prepared for presentation at the 2007 Fall Stripper Well Consortium held in Wichita, KS on October 30. The presentation was based primarily on the results of Humburg #1. A presentation was made at the 17^{th} Oil Recovery Conference in Wichita, KS on April 4, 2007. Made a presentation at the PTTC Gelled Polymer Workshop, Wichita, KS on April 1, 2008.

CONCLUSIONS

1. Two wells were treated in the Mississippian formation in the Schaben Field with conventional gelled polymer treatments to reduce water production followed by dehydration of the gel with crude oil after placement.
2. Sustained reduction in water production on the order of 250 to 300 B/D was observed after the treatments for both wells.
3. Oil production rates were reduced slightly by the treatment in both wells.
4. Little incremental oil was produced.
5. Reduction in electrical costs on the Humburg lease occurred after the treatment of Humburg #1. Estimated cost reductions averaged $500-600/month on the Humburg lease and are attributed to reduced water production in Humburg #1.
6. Production of incremental oil is necessary to make this process to reduce water production economic,
7. Chromium (III) in the water produced after the gel treatment ranged from 0.36 ppm after treating Humburg #1 to 0 ppm after treating Borger #1.

8. The concentration of polymer in water produced after the treatment peaked at 230 ppm TOC and declined with volume of water produced.

REFERENCE:

1. Carr, T.R, Green, D.W., and Willhite, G.P.: Improved Oil Recovery in Mississippian Carbonate Reservoirs of Kansas-Near Term—Class 2, U.S. Department of Energy Contract DE-FC22-93-BC14987, March 15, 1997

ACKNOWLEDGEMENTS:

Jack Gurley, Pickrell Drilling Inc and Scott Corsair, American Warrior Inc. supervised the field work conducted under this contract and their attention to details was essential in the successful completion of the field tests. Rodney Reynolds, now with Kinder Morgan, supervised pressure buildup data collection while a member of the Tertiary Oil Recovery Staff.